Acid Rain Program Policy Manual

Retired Questions

[This document contains Questions that have been retired from the Acid Rain Policy Manual. It is being provided for historical use only and should not be used for compliance. Please refer to the Revised Acid Rain Program Policy Manual for compliance information.]

U.S. Environmental Protection Agency
Acid Rain Division
Washington, D.C.

October 14, 1999

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Question 1.1 RETIRED

Topic: Designated Representative

Question: Our units are all affected under Phase II, so we will not have a designated representative at the time that monitor certification is required. Must the DR submit the petition, or may the owner/operator submit it?

Answer: A designated representative must be selected, because with one minor exception described below, the designated representative (or the alternate designated representative) is the only person for an affected utility who may make submissions to EPA under the Acid Rain Program. While the owner or operator is responsible for meeting the substantive requirements of the monitoring rule (such as installing monitors and conducting certification tests), only the designated representative is authorized to submit monitoring plans, certification applications, quarterly data reports, and petitions.

However, the monitoring rule does allow the designated representative <u>or</u> the owner or operator to submit notifications of certification test dates, because in some cases these notifications may be provided by telephone.

References: § 75.60(b)

Key Words: Certification applications, Designated representative

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 1.6 RETIRED

Topic: Monitoring Plan and Report Review Procedures

Question: In the past it seems that priority for review of monitoring plans and quarterly reports has been given to the coal plants. We have submitted several monitoring plans and EDRs for various clients but rarely receive comments or feedback. Is there any plan (or schedule) to expedite comments (especially for new units, gas-fired units, and cogeneration units)?

Answer: The EPA has prioritized the review of monitoring plans. In general, monitoring plans for oil and gas-fired units are reviewed after monitoring plans for coal-fired units. All quarterly reports are reviewed by EPA analysts, and letters and results of error checks are sent to Designated Representatives.

References: N/A

Key Words: Monitoring plans, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 1.7 RETIRED

Topic: Potential Upgrades to ETS-PC

Question: Does EPA intend to upgrade ETS-PC to include enhancements that have been suggested by users of the software?

Answer: The EPA is considering whether or not to upgrade ETS-PC, depending on the level of resources and utility interest. The Agency is keeping a record of suggested enhancements, including the following:

(1) Provide checks for calibration.

(2) Allow for specific record tests to check for their existence or the existence of any related records required, such as the relationship between concentration type records and mass type records.

(3) List the line numbers or dates of each error occurrence in addition to the total number of errors. This would streamline the error verification process and allow the user to verify that the user has found the exact errors that ETS has identified.

(4) Add back in the feature in ETS-PC version 2.0 that displayed the first 20 occurrences, rather than just the first occurrence, when using the error "snapshots" of records.

References: N/A

Key Words: N/A

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 1.8 RETIRED

Topic: ETS-PC Issues

Question: What is EPA's policy on the following miscellaneous issues involving ETS-PC?

Answer:

Issue: ETS-PC indicates errors for RT 420, column 34, which is indicated as "reserved." We have found that by placing a "!" in front of the item in the data dictionary (the DICTION.DAT file) it will ignore it and reduce the error count. What are we supposed to do for "reserved" columns? Presently we enter nothing. The following responses are provided to each of the four listed concerns:

Policy: You can edit the "reserved" line in the data dictionary as you described to suppress any error messages. It is appropriate to leave the "reserved" columns blank.

Issue: Error code 1399 is not defined in the ETS-PC "RANGEDIT.LOG" file.

Policy: This also relates to the data dictionary issue for Record Type 420 described above. The RANGEDIT.LOG file does not contain error codes for "reserved" columns. However ETS-PC will generate a range error with code 1399 (displayed in the RANGE.LOG file) if a value greater than "0" is entered in the "reserved" columns 34-46 in RT 420. The "reserved" columns should be left blank.

Issue: ETS-PC no longer gives the seriousness of errors (Fatal, Serious, ..., Information). Must ALL errors be eliminated prior to submission?

Policy: No. However, you should investigate all indicated errors prior to submission to determine their cause. If you determine that an error exists, you should attempt to eliminate the error (to the extent permitted according to EPA guidance) before submitting the report. If you need assistance in interpreting the error messages, please contact EPA's ETS-PC technical support contractor (Perrin Quarles Associates, Inc., (804) 979-3700). While many errors can be resolved quickly, some errors may require software changes or additional research which cannot be completed prior to the submission. You should briefly describe these cases in the documentation accompanying the quarterly report.

In some cases ETS-PC may generate error messages in response to valid data reported for a certain unit or stack.

This will most likely occur because a reported valid value falls outside the default range defined in ETS-PC's data dictionary (DICTION.DAT). If this is the case you can disregard the error message.

References: N/A

Key Words: Electronic report formats

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 1.9 RETIRED

Topic: ETS-PC Issues

Question: Is it possible to configure the ETS-PC software to provide an error message whenever a complete record type is missing? Example: RT 201 (NO_x concentration) should not be present when missing data calculations are applied to the NO_x emission rate for RT 320 (NO_x emission rate). I have tried setting the T/F flag to "T" for the entire record type, but I have not been able to trigger a message calling out the absence of RT 201, or any other record types when they are missing.

Answer: It is not possible for the user to modify ETS-PC to perform the record correlation checks you describe. Currently the PC software only performs format, readability, and range checks on the fields in each record contained in a quarterly report. The data dictionary's T/F flag only indicates whether a blank is allowed to be entered in a particular field within a reported record type; it does not enable the software to check for the presence or absence of a record type.

The EPA is considering whether or not to upgrade ETS-PC, depending on the level of resources and utility interest. The Agency will keep a record of this suggested enhancement.

References: N/A

Key Words: Electronic report formats

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 1.10 RETIRED

Topic: ETS-PC Issues

Question: Will ETS-PC still substitute missing data for records it cannot understand (i.e., method codes)? How will EPA feed this back to utilities?

Answer: ETS-PC version 2.2 enables utilities to perform readability, format, and range checking on each record contained in a quarterly report prior to submitting it to EPA. The ETS-PC software only flags potential errors and does not substitute missing data or otherwise change the contents of a quarterly report in any manner.

Currently EPA also provides written feedback to each utility's Designated Representative in response to each quarterly report. This feedback is generated by EPA's mainframe ETS software, which performs additional data checks. The EPA expects to expand this feedback in the future as enhancements are implemented in the mainframe software.

References: N/A

Key Words: Missing data

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 2.2 RETIRED

Topic: Appendix D Procedure - Common Stack Provisions

Question: Where there is a common pipe header, can the provisions of common stack monitoring be applied to the optional procedures in Appendix D?

Answer: Yes. As long as the total SO_2 emissions coming from each plant are accounted for, fuel flow monitoring and oil sampling could be performed upon each oil source, rather than each unit.

The monitoring plan should indicate the fuel flowmeter location. The source must then either combine allowances for compliance purposes or submit a petition for a method of emissions apportionment with the monitoring plan, as in a common stack situation.

References: App. D, § 75.16

Key Words: Common stack, Excepted methods, SO_2 monitoring

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 2.3 RETIRED

Topic: Appendix D Procedure - Sulfur Content Determination

Question: If a plant chooses to account for SO_2 emissions from natural gas by determining the sulfur content in the fuel (option (1) of 2.4 of Appendix D), would it be possible to have the natural gas suppliers measure sulfur content for the plant?

Answer: Yes, as long as ASTM D1072-90, "Standard Test Method for Total Sulfur in Fuel Gases," is used to determine sulfur content of the gas, there would not be a problem with a natural gas supplier determining sulfur content on a daily basis.

References: App. D (2.4)

Key Words: Excepted methods, Gas-fired units

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 2.4 RETIRED

Topic: Appendix D Procedures - Daily SO_2 Emissions

Question: What is the "SO_2 emission rate listed in NADB" referred to in § 2.4 of Appendix D of part 75?

Answer: The rate is 0.0006 lb SO_2/mmBtu for a unit combusting pipeline natural gas. This value is from the supporting documentation for the National Allowance Database (NADB). For units combusting natural gas that does not come from a pipeline, the NADB emission rate is the larger SO_2 emission rate of the two rates listed in the fields "SO2RTE" and "RY_ER" in the National Allowance Database.

References: App. D (2.4)

Key Words: Excepted methods, SO_2 monitoring

History: First published in August 1994, Update #3; retired in October 1999 Revised Manual

Question 2.5 RETIRED

Topic: Requirements for Appendix D Testing for Gas-fired Units Burning Emergency Fuel

Question: A gas-fired unit uses oil only as emergency fuel. May a utility use a petitioning process to become exempt from Appendix D testing for oil for that unit?

Answer: No, Appendix D testing is still required for the emergency fuel, because it is possible to test fuel flowmeters without combusting the emergency fuel.

Note that under the provisions of § 75.4(g) in the direct final rule published May 17, 1995, a unit applying for certification of Appendix D monitoring systems must complete certification testing 30 unit operating days after the date on which the unit first combusts the emergency fuel after January 1, 1995.

In documentation to be submitted with the quarterly report, identify the exact dates and hours when the unit combusts emergency fuel.

References: § 72.2, § 75.4(g), § 75.61(a)(6), App. D

Key Words: Excepted methods, Gas-fired units, NO_x monitoring, SO_2 monitoring

History: First published in March 1995, Update #5; revised July 1995, Update #6

Question 2.13 RETIRED

Topic: "Contractual" Sulfur Content of Natural Gas with no Contract

Question: The source's primary fuel is wood. Natural gas is used for almost daily start ups, as well as for periods when there is a problem with the wood handling system. There is no "contract" for the gas; it is purchased as needed on a take-or-pay basis. What is the requirement, if any, for sulfur analysis in this situation?

Answer: To fulfill the requirement of Appendix D, section 2.3.2.2, information is needed demonstrating that the gas has a hydrogen sulfide content of 1 grain/100 scf or less and a total sulfur content of 20 grains/100 scf or less. This information may be provided from the gas supplier whether or not there is a contract. In other words, the utility is responsible for obtaining the information on the hydrogen sulfide content and the total sulfur content of the gas, regardless of whether that gas is purchased as part of a long- term contract or as part of a spot purchase. The information should be provided in the monitoring plan and should be representative of the previous year.

References: App. D (2.3.2.2)

Key Words: Excepted methods, Gas-fired units, SO_2 monitoring

History: First published in November 1995, Update #7

Question 2.14 RETIRED

Topic: Appendix D Calculations - GCV and Density

Question: For gross calorific value (GCV) and density, must we use the maximum of 30 days like in % sulfur procedures, or can we use the value directly? Also, what requirements apply to DAHS verification with respect to density?

Answer: Use that day's measured GCV or density value directly to calculate SO_2 mass emissions and heat input. Report this GCV in column 34 and use a data source code of 0 in column 44 of RT 302. Report today's density value in column 75 and use a data source code of 0 in column 88 of RT 302. The following table summarizes the use of actual daily values or highest value in the last 30 days for applicable scenarios and parameters for daily manual oil samples.

Question 2.15 RETIRED

Topic: Definition of Pipeline Natural Gas and Applicability of Default SO_2 Emission Rate

Question: What is pipeline natural gas? Why is the use of the default SO_2 emission rate of 0.0006 lb/mmBtu restricted to pipeline natural gas?

Answer: Section 72.2 defines "pipeline natural gas" as "natural gas that is provided by a supplier through a pipeline." Natural gas is defined as "a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) containing 1 grain or less hydrogen sulfide per 100 standard cubic feet, and 20 grains or less total sulfur per 100 standard cubic feet, produced in geological formations beneath the Earth's surface, and maintaining a gaseous state at standard atmospheric temperature and pressure under ordinary conditions."

As EPA explained in the technical support document to the revised Part 75, the default SO_2 emission rate of 0.0006 lb/mmBtu was derived from EPA's AP-42 emission rate factor for pipeline natural gas. This emission rate factor is based upon an average sulfur content of 0.2 grains of total sulfur per 100 standard cubic feet (scf). Note that this is only 1 percent of the sulfur content used in § 72.2's definition of natural gas. When natural gas is transported through a pipeline, it often is refined to "sweeten" or remove sulfur from the natural gas. Thus, the average sulfur content of pipeline natural gas is significantly lower than the possible sulfur content of other natural gas or other gaseous fuels. In order to prevent underestimation of emissions, the default emission rate of 0.0006 lb/mmBtu may only be used for pipeline natural gas which, on average, contains no more than 0.2 grains of total sulfur per 100 scf. To demonstrate that the default emission rate for pipeline natural gas may be used, a utility need only demonstrate that the natural gas was supplied through a pipeline supplier. The default emission rate for pipeline natural gas must not be used for "sour" natural gas pumped directly from a field, nor may it be used for other gaseous fuels, such as liquified petroleum gases, gasified coal or digester gas.

Gaseous fuels other than pipeline natural gas may be monitored using daily gas sampling under Appendix D if the sulfur content of the gaseous fuel is no more than the sulfur content of natural gas, i.e., less than 20 grains/100 scf, and the hydrogen sulfide content is 1 grain/100 scf or less. To demonstrate that a unit qualifies to use Appendix D when combusting a gaseous fuel, the utility must show that the gaseous fuel has a hydrogen sulfide content of 1 grain/100 scf or less and a total sulfur content of 20 grains/100 scf or less. If contractual information on the sulfur content is available, that information may be used. If there is no contract for the gas, the utility may provide fuel sampling data to show its sulfur content.

References: § 72.2, § 75.11(e), App. D (2.3.1 and 2.3.2), App. F (section 7)

Key Words: Excepted methods, Gas-fired units, SO_2 monitoring

History: First published in March 1996, Update #8; revised June 1996, Update #9

Fuel Sampling: Use of Actual Daily Values Vs. Highest Value in Last 30 Days			
Use of Data	**Sulfur**	**Density**	**GCV**
Report in 302/303	Actual daily value	Actual daily value	Actual daily value
Use in normal calculations	Highest in last 30 days	Actual daily value	Actual daily value
Use in missing data calculations	Highest in last 30 days	Highest in last 30 days	Highest in last 30 days

It is not necessary to show which density value is regularly used in calculations as part of verification of the DAHS. However, do verify that your DAHS correctly implements the formulas for calculating mass of oil and SO_2 mass emissions (equations D-2 and D-3).

References: App. D (2.4.1 and 2.4.2)

Key Words: DAHS, Electronic report formats, Excepted methods, Fuel sampling, SO_2 monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 3.1 RETIRED

Topic: Flow Profile Testing

Question: Appendix A (Section 1.2) requires flow profile testing for all flow monitor installations. In many instances this represents time-consuming and expensive testing. Will EPA waive this testing where the siting criteria are met and the monitor passes the relative accuracy performance test?

Answer: EPA recognizes that cyclonic flow testing would be unnecessary for most installations that meet the minimum EPA Method 1 siting criteria with respect to distance from flow disturbances.

Therefore, in the final rule, EPA has revised the text in Section 1.2 of Appendix A to clarify that flow profile testing is recommended, but not required.

References: App. A (1.2)

Key Words: Flow monitoring, Monitor location

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 4.1 RETIRED

Topic: Appendix E - Testing

Question: In the Appendix E optional NO_x estimation procedure (published January 11, 1993), a tremendous amount of time and effort is going to be required to develop load versus efficiency curves for units opting to use this procedure. Why is this data being developed when it appears that the data will not be recorded or reported?

Answer: The direct final rule published on May 17, 1995 no longer requires unit efficiency testing as part of the alternative NO_x monitoring procedures in Appendix E.

References: § 75.12(c), § 75.51(d), § 75.64(a), App. F

Key Words: Excepted methods, NO_x monitoring

History: First published in original March 1993 Policy Manual; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 4.4 RETIRED

Topic: Appendix E - Testing

Question: Under the NO_x procedures specified by Appendix E of Part 75 (published on January 11, 1993), gas-fired peaking units and oil-fired peaking units other than stationary gas turbines are required to conduct NO_x testing procedures at three excess oxygen levels. Are there any conditions under which such a unit may conduct these testing procedures at just one excess oxygen level?

Answer: The direct final rule published on May 17, 1995 no longer requires testing at multiple excess O_2 levels as part of the NO_x monitoring procedures in Appendix E.

References: App. E (2.1.2.1)

Key Words: Excepted methods, NO_x monitoring

History: First published in May 1993, Update #1; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 4.5 RETIRED

Topic: Excepted Methods - Recordkeeping

Question: The Acid Rain CEM rule seems to contradict itself on the recordkeeping requirements under the NO_x procedures specified by 40 CFR Part 75, Appendix E. The rule and appendix specify hourly records while the recordkeeping section specifies daily records. Should these records be maintained on an hourly or daily basis?

Answer: Hourly. If using the Appendix E procedure, then the owner or operator of a gas-fired peaking unit or oil-fired peaking unit must "provide information satisfactory to the Administrator using the procedure in Appendix E of this part for estimating hourly NO_x emission rate," as specified by 40 CFR 75.12(c)(ii). In addition, the procedures specified in the Appendix are designed to produce hourly NO_x emission rates; after following the initial testing procedures to establish the NO_x emission rate-unit load correlation, Section 2.4 specifies the "procedures for determining hourly NO_x emission rate." Although the recordkeeping provisions under § 75.51(d) specify "daily" parameters, the substantive portions of the rule are clear, and the owner or operator using Appendix E must record and report the parameters to provide EPA with the hourly NO_x emission rate. Therefore, the electronic reporting format correctly specifies that owners and operators using Appendix E are to record and report hourly fuel flows and hourly NO_x emission rates. Furthermore, recording and reporting these parameters on an hourly basis satisfies the requirements of § 75.51(d).

References: § 75.12(c)(ii), § 75.51(d), App. E (2.4)

Key Words: Excepted methods, NO_x monitoring, Recordkeeping

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 4.6 RETIRED

Topic: Appendix E - Testing

Question: Under the NO_x procedures specified by Appendix E (as published January 11, 1993), stationary gas turbines are required to conduct NO_x testing procedures at the normal excess oxygen level at each load, "and again at another excess oxygen level if the temperature of the (combustion) air at the air intake varies by more than 4°F from the average test conditions at that load." Does this mean that the testing procedures must be conducted repeatedly at every 4° interval of combustion air temperature possible?

Answer: The direct final rule published on May 17, 1995 no longer requires testing at multiple excess O_2 levels as part of the NO_x monitoring procedures in Appendix E.

References: App. E (2.1.2.1)

Key Words: Excepted methods, NO_x monitoring

History: First published in May 1993, Update #1; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 4.8 RETIRED

Topic: Appendix E - Testing

Question: Appendix E of Part 75 (as published on January 11, 1993) requires testing for "each fuel [gas or oil] and each combination of fuels." May we develop "gas-only" and "oil-only" curves, and then use the higher emission value during the short periods of co-firing?

Answer: No. Section 2.4.3 of Appendix E in the direct final rule published May 17, 1995 explains that when a unit combusts a combination of fuels for which a correlation has not been developed, the NO_x emission rate for each fuel should be determined based on the heat input of that fuel and then a Btu-weighted average emission rate should be calculated.

References: App. E (2.4.3)

Key Words: Certification tests, Excepted methods

History: First published in November 1993, Update #2; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 4.11 RETIRED

Topic: Appendix E - NO_x Correlation Procedures

Question: Appendix E of part 75 (as published January 11, 1993) requires development of a NO_x versus unit load correlation. Is it acceptable to develop a correlation of NO_x versus heat input?

Answer: The direct final rule published on May 17, 1995 requires units to develop NO_x versus heat input correlations. However, any utility that completed its Appendix E testing for a unit and submitted a certification application before July 17, 1995 may continue to use a NO_x versus unit load correlation to report hourly NO_x emissions until the next time it performs its NO_x correlation testing.

References: App. E (1.2.2, 2.1.3, 2.4)

Key Words: Excepted methods, NO_x monitoring, Peaking units

History: First published in October 1994, Update #3; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 4.14 RETIRED

Topic: Requirements for Low NO_x Emitters

Question: For low NO_x emitters, is it always necessary to install dual range monitors? Also, Protocol 1 gases do not exist at the low levels required for the linearity test. How do we perform linearity tests if there are no Protocol 1 gases available at these low levels?

Answer: If a utility installs control equipment to reduce NO_x and has a state or local permit which limits its emissions to below 10 ppm, the utility may install a monitor which covers only the NO_x concentration for the normal unit operating range. If the unit exceeds this range at any time within 3 hours of startup or shutdown, it must report the maximum NO_x emission rate for the hour. If a unit exceeds this range at any other time, the utility must install and certify a dual range monitor. Until this monitor is certified, the utility would report any exceedance of the low scale range as the maximum NO_x emission rate.

If the low scale span associated with the monitor is 10 ppm or less, doing a test at one non-zero concentration in that range will satisfy the linearity check requirement. Since the monitor only has to be within 5 ppm of the gas tag value, tests at additional points are not required. These requirements only apply for the purpose of EPA's Acid Rain regulations. Since many of the sources that may fit this description are in ozone nonattainment areas, they may already be subject to stricter State requirements.

References: App. A

Key Words: Dual-range monitors, Linearity, NO_x monitoring

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 4.18 RETIRED

Topic: Appendix E - Retesting

Question: In Section 2.3.3, does the described "2 percentage point exceedance" of excess O_2 refer to 2 percentage points more than the expected O_2 or a 2 percentage point variance from the expected O_2? If a variance, what happens if gas and oil are tested separately and the respective excess O_2 readings are not the same -- is the allowable excess O_2 exceedance 2 percentage points above the highest expected O_2 and 2 below the lowest (resulting in a range over 4%), or 2 points above the lowest and 2 points below the highest (resulting in less than 4%), or 2 points plus or minus the average? What if the excess O_2 in the separate gas and oil tests are already 2 or more percentage points apart?

Answer: The term "exceed" means that the excess O_2 is **more** than the excess O_2 during the most recent baseline test.

If two or more fuels are being co-fired, then look at the parametric value that would be highest for all fuels. For example, if the excess O_2 were at 1.0% excess O_2 for gas and at 3.0% excess O_2 for oil, then the excess O_2 during co-firing would need to rise above 5.0% excess O_2 before the excess O_2 would be beyond the specified limit. If the excess O_2 remained above 5.0% excess O_2 for 16 consecutive unit operating hours, then testing would be retriggered for both oil and gas.

References: App. E (2.3.3)

Key Words: Excepted methods, NO_x monitoring

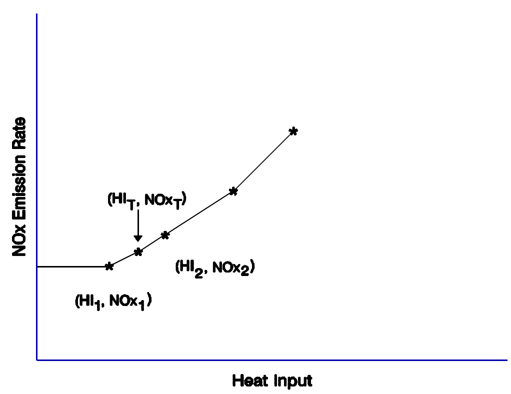
History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 4.22 RETIRED

Topic: Formula Verification for Appendix E

Question: Policy Manual Question 4.13 (revised) provides a checklist of requirements for the certification application of Appendix E units. Items 1 and 5 reference the formulas for the line segments of the NO_x correlation curves. What is an example of a formula?

Answer: Appendix E indicates that there should be straight line segments between each measured point, and a horizontal line from the lowest heat input point to the y-axis. Therefore, there will be a formula for each line segment on the curve. See the example graph below.



Formulas would be in the following format:

$$NO_{x\,T} = \left[\frac{NO_{x\,2} - NO_{x\,1}}{HI_2 - HI_1}\right]\left(HI_T - HI_2\right) + NO_{x\,2}$$

Where,

NOx_T	=	NO_x emission rate for this fuel at time T;
HI_T	=	instantaneous hourly heat input rate at time T;
NOx_1	=	NO_x emission rate at heat input point 1 (lowest heat input rate);
NOx_2	=	NO_x emission rate at heat input point 2 (next higher heat input rate);
HI_1	=	instantaneous heat input rate at heat input point 1 (lowest heat input rate); and
HI_2	=	instantaneous heat input rate at heat input point 2 (next higher heat input rate).

Note that the heat input rate is an instantaneous rate and not a total heat input for the hour. For example, if the instantaneous heat input rate is 5,000 mmBtu/hr where the unit combusts a fuel for only 15 minutes in the hour, use 5,000 mmBtu/hr as the heat input rate. Do not use a total heat input of 1,250 mmBtu for the hour.

References: App. E (2.1.6)

Key Words: Certification applications, Excepted methods, NO_x monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 8.10 **RETIRED**

Topic: RATA Procedure

Question: Are there circumstances under which relative accuracy tests would not be counted as one of two attempts to attain reduced RATA frequency?

Answer: Yes. If the reference method fails to perform properly and the RATA is ended after three runs or less, then the test would be annulled. (If more than three runs are performed, EPA assumes that the utility has evaluated the situation and has decided to complete a test.) These runs would not need to be reported. The annulled test also would not count as one of two attempts to reduce RATA frequency. RATA testing performed before the dates in the certification testing notification would also not need to be reported to EPA or counted toward the RATA frequency.

If the RATA is terminated because of problems with the installed CEMS or flow monitoring system that is being certified, it must be reported and counted for purposes of RATA frequency. (This includes monitoring hardware problems and software problems where the raw monitor data cannot be recorded by the DAHS.) If a monitor is having difficulty in performing during the test, then it should not have a reduced RATA frequency. If any adjustments or recalibrations are performed upon the monitor to be certified, then the utility is indicating that it is aware some sort of problem exists.

References: App. A (6.5.9), App. B (2.3.1)

Key Words: Certification tests, RATAs

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 8.13 RETIRED

Topic: Concurrent SO_2 and Flow RATA

Question: For a base-loaded unit, at what load should the concurrent SO_2 flow RATA and the flow bias test be conducted?

Answer: Conduct these tests at the normal load. For a base-loaded unit, the normal level may be within 10% of the high load level, which triggers the 3 load flow RATA to be conducted at the low load level, an evenly-spaced mid-load level and the high (normal) load level.

References: App. A (6.5.2)

Key Words: Certification tests, RATAs

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 8.14 RETIRED

Topic: Requirements for Concurrent Flow/SO_2 RATAs

Question: If, during a concurrent flow/SO_2 RATA, one monitoring system passes, but the other system fails, does the concurrent RATA have to be repeated, or just the RATA for the system that failed?

Answer: Repeat only the RATA for the system that failed. The results of the failed test must be reported to the Agency, however, in electronic format. For each run of the failed RATA, use a run "flag" of "**9**" in Column 62 of Record Type 610 of the EDR format to indicate, "Run not counted; RATA failed or discontinued". See Question 8.16 for more information on reporting.

References: App. A, 6.5, EDR V1.1

Key Words: Certification tests, Electronic report formats, RATAs, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 10.14 RETIRED

Topic: Use of Calibration Policy

Question: If I have a unit that completes its provisional certification after January 1, 1995, may I use the calibration policy published in Policy Manual Update #5, based on a calibration that occurred before I was provisionally certified? For example, if I was operating and passed a calibration at 8 AM on April 1, 1995, and then successfully completed my last certification test at 3 PM on April 1, 1995, does the calibration at 8 AM on April 1, 1995, validate data until 10 AM on April 2, 1995?

Answer: Yes, data can be validated based on a calibration that occurred just prior to provisional certification. This applies to both the general calibration policy and the startup calibration policy. The calibration that was performed before the provisional certification date must be reported in order to validate the data.

References: App. B (2.1.1)

Key Words: Calibration, Reporting

History: First published in July 1995, Update #6

Question 10.20 RETIRED

Topic: Daily Calibration Tests

Question: Policy Manual Questions 10.7 and 10.13 relate to Part 75, Appendix B, section 2.1, "Daily Assessments." The interim final technical revisions to Part 75 published May 17, 1995 reflect the answer given to Question 10.7. The technical revisions do not discuss the issue of a start-up grace period that was answered in Question 10.13. Does the answer to Question 10.13 stand?

Answer: Yes. From January 1, 1996 utilities must use the answer in Policy Manual Question 10.13 to validate data.

References: App. B (2.1), Policy Manual Questions 10.7 and 10.13

Key Words: Calibration error, Reporting

History: First published in November 1995, Update #7

Question 12.2 RETIRED

Topic: Certification Application Deadlines

Question: The rule requires Phase I systems to be certified by November 15, 1993. What is the last day that certification test results can be submitted to EPA to comply with this requirement?

Answer: Since the certification testing deadline for these units is November 15, 1993 [see 40 CFR § 75.4(a)(1)], and since a certification application must be submitted within thirty (30) days after the completion of testing [see 40 CFR § 75.63(a)], the last day that certification test results can be submitted is December 15, 1993.

References: § 75.4(a)(1), § 75.63(a)

Key Words: Certification applications, Deadlines

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 12.4 RETIRED

Topic: Certification Process Deadlines

Question: What are the milestones and deadlines for CEM system installation, testing, and certification for a Phase I unit?

Answer: For Phase I units, certification testing must be conducted by November 15, 1993 [see 40 CFR § 75.4(a)(1)]. A pre-test notification and a monitoring plan must be submitted at least forty-five (45) days prior to certification testing [see 40 CFR § 75.20(a)(1) and 40 CFR § 75.62(a)]. No later than thirty (30) days after the testing, a certification application based upon the results of the testing must be submitted [see 40 CFR § 75.63(a)]. For Phase I units, the deadline for submittal of the first quarterly emissions report is January 30, 1994, and the time period covered by this report is from November 15, 1993, until December 31, 1993 [see 40 CFR § 75.64(a)].

References: See text above

Key Words: Deadlines, Notice, Reporting

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 12.5 RETIRED

Topic: Certification Deadline for Substitution/Compensating Units

Question: What is the certification testing deadline for Phase II units brought into Phase I as substitution units or compensating units?

Answer: If the units are brought into Phase I as substitution or compensating units, the certification testing deadline would be the later of the following dates specified in 40 CFR § 75.4(a)(2):

-- November 15, 1993, or

-- Not later than 90 days after the permit issuance date (or date of approval of a permit revision) of the acid rain permit which governs the unit and contains the approved substitution plan or reduced utilization plan.

However, if the relevant compliance plan is activated after October 1, 1994, then such units would be subject to the same certification testing deadlines as other Phase II units -- January 1, 1995 -- despite the fact that this would be less than 90 days after approval for substitution into Phase I.

References: § 75.4(a)(2)-(3)

Key Words: Deadlines, Substitution/Compensating units

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 12.6 RETIRED

Topic: QA/QC Maintenance after Early Certification

Question: Once certification testing has been performed, do the CEM systems need to be operated and maintained according to the regulations, even if the certification testing was completed "early" (prior to the applicable deadline, i.e., November 15, 1993 for Phase I units and January 1, 1995 for Phase II units)?

Answer: Regardless of the date of certification testing, the monitoring system should be operated and maintained in accordance with Part 75 following completion of the testing. The basis for this determination is Section 2.1 of Appendix B to 40 CFR Part 75, which indicates that the requirement to conduct daily assessments on the monitoring system is effective as of the day when certification testing on the system is completed. According to Section 2.2 of Appendix B to 40 CFR Part 75, the schedule for quarterly monitoring system assessments is also determined based upon the date when the monitoring system is provisionally certified (i.e., upon completion of certification testing). Since the effective dates for these quality assurance activities are based upon the date of certification testing, the monitoring system should be maintained and operated in accordance with Part 75 once the certification testing is completed.

References: App. B (2.1-2.2)

Key Words: Certification tests, Quality assurance

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 12.10 RETIRED

Topic: Certification Deadlines

Question: Will there be any extensions to the CEMS equipment certification deadlines if stack testing companies are unavailable?

Answer: No. The source may also perform certification tests.

References: § 75.4

Key Words: Certification process, Deadlines

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 12.15 RETIRED

Topic: Cycle Time/Response Time Test

Question: Appendix A, Section 6.4 (*Cycle Time/Response Time Test*) requires that the calibration gas be injected at the "injection port." Does this mean that the gas should be injected at the probe?

Answer: Yes, the gases in the cycle time/response time test should be injected at the probe to properly measure the cycle time/response time of the measurement system. To inject at any other location would defeat the purpose of the test since it is primarily designed to insure that extractive monitoring systems with gas handling systems can properly pull a sample and analyze it in the required response time for the Acid Rain CEM Program (15 minutes).

References: App. A (6.4)

Key Words: Certification tests, Cycle time/response time

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 12.16 RETIRED

Topic: Installation and Certification Deadlines for Shutdown Units

Question: If a unit is shutdown on the applicable monitoring deadline for CEMS (January 1, 1995 for Phase II units or November 15, 1993 for Phase I units), must the unit install a CEMS by the compliance date and then may wait to complete certification testing within 90 days after recommencement of commercial operation?

Answer: No. If a unit is shutdown on the compliance data, §75.4(d) requires both installation of the CEMS at the unit and completion of the certification tests no later than 90 days following the recommencement of commercial operation.

The designated representative should notify EPA of the dates when the unit will be shutdown and when the unit is planned to recommence commercial operation. Submit this notification no later than the original compliance deadline for the unit (January 1, 1995 for Phase II units or November 15, 1993 for Phase I units). Again notify EPA when the unit actually recommences commercial operation. Note that the definition of "commence commercial operation" in §72.2 means to have begun generation of electricity for sale, including the sale of test generation.

References: § 75.4(d)

Key Words: Deadlines, Shutdown units

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 12.20 RETIRED

Topic: Certification Deadline Delay for Oil and Gas-Fired Units for NO_x and CO_2 Monitoring

Question: Has the extension for the CEM certification for NO_x and CO_2 monitoring at oil-fired units and gas-fired units taken effect?

Answer: Yes. EPA published a notice of direct final rulemaking and a notice of proposed rulemaking in the Federal Register on Thursday, August 18, 1994 (59 FR 42509-42511, 59 FR 42560). These rulemakings extend the CEM certification deadline for NO_x and CO_2 monitoring at oil-fired units and gas-fired units. Those gas-fired and oil-fired units in ozone nonattainment areas or in the ozone transport region will have their NO_x and CO_2 certification deadline extended by 6 months to July 1, 1995; gas-fired and oil-fired units outside of ozone nonattainment areas or outside of the ozone transport region will have their NO_x and CO_2 certification deadline extended by 12 months to January 1, 1996.
No comments on the direct final rule were received by the Agency by October 19, 1994; therefore, the effective date of the

amendment to part 75 is October 17, 1994. A complete copy of the notice is located in the file certext.wpf on both the CAAA and the EMTIC bulletin boards of EPA's Technology Transfer Network.

This extension does not affect coal-fired units. It also does not relieve gas-fired and oil-fired units from the requirement to certify an SO_2 monitoring system or for oil-fired units to meet opacity monitoring requirements.

References: § 75.4(a)

Key Words: CO_2 monitoring, Gas-fired units, NO_x monitoring, Oil-fired units

History: First published in November 1994, Update #4; retired in October 1999 Revised Manual

Question 12.21 RETIRED

Topic: Certification Procedure for Oil and Gas Units for SO_2

Question: What are the SO_2 certification procedures for oil-fired units and gas-fired units?

Answer: The NO_x and CO_2 deadline extension discussed in Question 12.20 does not include an extension for SO_2 monitoring (or, opacity monitoring, if appropriate), for which appropriate systems must be installed and certified by January 1, 1995.

If a utility chooses to install a NO_x monitoring method by January 1, 1995, then the designated representative (DR) for the unit must file all the appropriate submissions based on the certification testing dates for the NO_x monitoring method (as outlined in Question 12.14).

If the utility takes advantage of the deadline extension for NO_x and CO_2 monitoring, then the designated representative for the unit should file all the appropriate submissions for SO_2 based on the certification deadline of January 1, 1995. (The submissions for NO_x and CO_2 would be submitted separately later).

Specifically, the DR should submit an initial monitoring plan by November 15, 1994 (45 days before the certification deadline). A certification test notification for SO_2 is not required. Provisional certification of the SO_2 monitoring system would take effect on January 1, 1995. Finally the DR must submit a certification application for SO_2 (and opacity, if applicable) by January 30, 1995. The certification application should include the following:

- ! A revised monitoring plan
- ! The fuel flow meter accuracy, upper range value, and span
- ! A description of the fuel flow meter accuracy calibration method:

  (a) identifying a method described in Appendix D Section 2.1.1;
  (b) identifying a method using AGA Report No. 3; or
  (c) describing of an alternative procedure which satisfies the petition requirements under § 75.23

- ! A description of the DAHS verification tests performed for formula verification and for missing data (see Question 15.9)

References: § 75.20, § 75.23, § 75.53, App. D

Key Words: Gas-fired units, Oil-fired units, Reporting, SO_2 monitoring

History: First published in November 1994, Update #4; retired in October 1999 Revised Manual

Question 12.22 RETIRED

Topic: Applicability of NO_x and CO_2 Deadline Extensions to Conditional Substitution Units

Question: If a gas-fired unit or oil-fired unit listed in a substitution plan becomes an active substitution unit after January 1, 1995, does the certification deadline extension for NO_x and CO_2 monitoring still apply?

Answer: Yes. Because the substitution plan was conditional on January 1, 1995, EPA considers the appropriate certification deadline for NO_x and CO_2 in §75.4(a)(4) to be the relevant deadline. For gas-fired units or oil-fired units in ozone nonattainment areas or in the ozone transport region, the deadline is July 1, 1995; for gas-fired units or oil-fired units neither in ozone nonattainment areas nor in the ozone transport region, the deadline is January 1, 1996.

References: § 75.4(a)

Key Words: Certification applications, CO_2 monitoring, Gas-fired units, NO_x monitoring, Oil-fired units, Substitution/compensating units

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 12.24 RETIRED

Topic: Certification Deadlines

Question: The revised certification deadline for NO_x and CO_2 monitoring at gas-fired and oil-fired units published in the August 18, 1994 Federal Register became effective on October 17, 1994. A unit is located in a county that was outside of the ozone transport region but in an ozone non-attainment area on October 17, 1994, but the county comes into ozone attainment before July 1, 1995. What is the certification deadline for NO_x and CO_2 monitoring for a gas-fired or oil-fired unit in that county?

Answer: January 1, 1996. The unit is not in an ozone non-attainment area as of the July 1, 1995 deadline for units that are in ozone non-attainment areas or the ozone transport region.

References: § 75.4(a)(4)

Key Words: Certification deadlines, CO_2 monitoring, NO_x monitoring, Ozone non-attainment areas

History: First published in July 1995, Update #6; retired in October 1999 Revised Manual

Question 12.25 RETIRED

Topic: Certification Deadlines

Question: The revised certification deadline for NO_x and CO_2 monitoring at gas-fired and oil-fired units published in the August 18, 1994 Federal Register became effective on October 17, 1994. A unit is located in a county that was in an ozone attainment area as of October 17, 1994, but becomes an ozone non-attainment area after October 17, 1994. What is the certification deadline for NO_x and CO_2 monitoring for a gas-fired or oil-fired unit in that county?

Answer: January 1, 1996. The unit is in an ozone attainment area as of the effective date of the deadline for units that are in ozone non-attainment areas or the ozone transport region, and therefore, the utility would have originally scheduled its tests based upon the January 1, 1996 certification deadline. Because meeting a deadline that suddenly becomes 6 months earlier would be difficult, and because few units are in this situation, EPA believes that in this case, the unit should keep its original certification deadline of January 1, 1996.

References: § 75.4(a)(4)

Key Words: Certification deadlines, CO_2 monitoring, NO_x monitoring, Ozone non-attainment areas

History: First published in July 1995, Update #6; retired in October 1999 Revised Manual

Question 12.28 RETIRED

Topic: Certification Applications - File Naming Conventions

Question: What file naming convention should be used when submitting certification test data and results on disk?

Answer: Although EPA has established a file naming convention for the quarterly report files (note that a complete quarterly report file does include monitoring plan data and ongoing quality assurance data in addition to the hourly emissions data), EPA has not mandated a file naming convention for initial certification test data. A utility may follow essentially the same convention as was established for quarterly reports by including the ORISPL and unit identification in the first 8 digits of the filename, and then using the letters "cer" in the 3 digit extension to indicate that the disk contains certification data.

Filename Key: 12345678.abc [for illustration: 12345 6 78.ab c]

Digits 1-5 = ORISPL (the specific plant code assigned to each utility plant by DOE)

Digit 6 = File type indicator (U = single unit, C = common stack, M = multiple stack)

Digits 7-8 = Unit (or units) Identifier

Digits a-b = Year reported

Digit c = Quarter reported

For example: **00032U01.951**

For a disk containing certification data, the example is:
00032U01.CER

References: § 75.20

Key Words: Certification applications, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 12.29 RETIRED

Topic: Certification Deadlines and Notifications for Shutdown Units

Question: I have a gas-fired peaking unit in an ozone attainment area with a January 1, 1996 certification deadline for NO_x and CO_2 monitoring. What am I required to do if the unit is shutdown over that deadline?

Answer: If the NO_x and CO_2 monitoring systems for the unit have already been tested and provisionally certified, then submit the certification application no later than 45 days after the date of the last test. The latest possible date for submission would be February 15, 1996.

If the NO_x and CO_2 monitoring systems for the unit have not already been provisionally certified, there is a new certification deadline under § 75.4(d). The certification deadline becomes the earlier of the following dates: 45 unit operating days after the unit begins to combust fuel and sell electricity after January 1, 1996; or 180 calendar days after the unit begins to combust fuel and sell electricity after January 1, 1996. Note that if the unit is combusting fuel but not generating electricity on January 1, 1996, it is still considered to be operating and is required to meet the January 1, 1996 certification deadline.

In the case where the unit is shutdown (and not emitting) over the original deadline of January 1, 1996, the designated representative must notify EPA and the appropriate State and/or local agency of the unit shutdown and recommencement of commercial operation according to §§75.4(d) and 75.61. For an unplanned shutdown such as a shutdown due to unit dispatching, the notification must be submitted no later than 7 days after the shutdown date. In this case, the designated representative must provide notification no later than January 8, 1996. The notification must include the date of shutdown and the scheduled date of recommencement of commercial operation. If the exact date of recommencement of commercial operation is not known, estimate a month in which operation is likely.

If the unit later starts up on a date other than the specific date mentioned in the shutdown notification, or if an estimate of a month was originally provided, submit an additional notification no later than 7 days after the unit recommences commercial operation.

A sample notification should contain information such as the following:

> {Name of EPA Regional Contact or State contact}
> {Address of EPA Regional Office or State Agency}
>
> Re: Shutdown Unit Notification
>
> *This is to notify you that the following unit(s) at the following plant(s) were shutdown over the applicable certification deadline in §75.4(a) of 40 CFR part 75. I will notify you again of the date when the unit recommences commercial operation.*
>
> Plant Name: Mid-America Plant State: OH ORIS Code: 9999

NADB Unit ID	Date unit shutdown	Original certification deadline	Date unit expected to recommence commercial operation
1	3/15/95	1/1/96	6/96 (est.)

> *I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment*.

The EPA expects that the designated representative of all gas-fired and oil-fired units for which a certification application for NO_x and CO_2 monitoring systems has not previously been submitted will either: (1) submit a certification application 45 days after completing testing no later than February 15, 1996 or (2) submit a notification of shutdown 7 days after the unit is shutdown no later than January 8, 1996. Utilities not meeting these submission deadlines are in violation of Part 75.

References: § 75.4(d), § 75.61(a)(3)

Key Words: Certification deadlines, CO_2 monitoring, NO_x monitoring, Shutdown units

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 13.9 RETIRED

Topic: Implementation Timeframe for RTs 550 and 555

Question: If EPA requires submission of proposed RTs 550 and 555, what is the timeframe for requiring these records in a quarterly report?

Answer: To allow adequate time for utilities to implement software changes to support RTs 550 and 555, ARD will allow reporting of missing data information in hardcopy format at least through December 31, 1995. EPA requests that utilities submit information on recertification events beginning with the first quarter 1995 quarterly report for any system changes and modifications on or after January 1, 1995. This may be done in hardcopy or RT 555. Utilities may elect to use RT 550 in lieu of hardcopy documentation prior to 1996. ARD will establish in the near future a final deadline for the use of EDR RTs 550 and 555.

References: § 75.61, § 75.64

Key Words: Electronic report formats, Recertification, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 13.10 RETIRED

Topic: Software Requirements for RT 550 and 555

Question: If EPA requires submission of proposed RTs 550 and 555, can we create these records in software (such as word processing software or spreadsheets) other than Part 75 DAHS software and "merge" the records into the quarterly report?

Answer: Yes. EPA will allow creation and data entry of both RT 550 and 555 independent of the certified DAHS component, provided utilities "merge" these records into the quarterly report file according to the record ordering requirements of the EDR. RT

550 and RT 555 must be imported into the EDR in ASCII flat file format.

References: § 75.63, § 75.64

Key Words: DAHS, Electronic report formats, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 13.11 RETIRED

Topic: Software Changes Resulting from RT 550 and 555 Requirements

Question: If a utility implements DAHS software changes to create and report RTs 550 and 555, is it necessary to perform missing data tests or formula verification on the new version of the DAHS software?

Answer: No. It is not necessary to perform missing data tests or formula verification on the new version of the DAHS software if the only changes made are done to implement the reporting of RT 550 and 555. If other software changes are made at the same time as the software modifications needed to implement RTs 550 and 555, then DAHS verification and a daily calibration for each affected system is required.

References: § 75.63

Key Words: DAHS, Electronic report formats, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 14.1 RETIRED

Topic: Recordkeeping -- Significant Digits

Question: The quarterly reporting requirement for tons SO_2 (§ 75.64(a)(2)) is to the nearest thousandth or to the nearest two pounds. This number when calculated can only be resolved to 4 significant figures and does not allow for three places after the decimal. Is this interpretation of the calculation method incorrect?

Answer: Section 75.64(a)(2) was revised to require tons of SO_2 to the nearest tenth.

References: § 75.64(a)(2)

Key Words: Reporting, SO_2 monitoring

History: First published in Original March 1993 Policy Manual; retired in October 1999 Revised Manual

Question 14.9 RETIRED

Topic: Quarterly Electronic Report

Question: How may the quarterly electronic report be submitted within 30 days following the end of the calendar quarter?

Answer: Electronic reports may be submitted either by magnetic media (tape or floppy disk) or by direct electronic transfer (through a modem connection or INTERNET). "Submission" is defined in the permits rule (40 CFR 72.2) essentially as "the date of dispatch, transmission, or mailing." For example, for the first Phase I quarterly reports, magnetic media sent through the U.S. mail must be postmarked by January 30, 1994 and direct electronic transfer must be initiated prior to midnight on January 30, 1994.

References: § 72.2

Key Words: Reporting

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 14.10 RETIRED

Topic: Quarterly Electronic Report

Question: What kinds of magnetic media can be used to submit quarterly reports?

Answer: Either magnetic tape or magnetic PC floppy disk media is acceptable. Magnetic tapes must be accompanied by documentation indicating the recording density, logical record length, blocking type (fixed, variable, etc.), blocksize, tape format (IBM, ANSI, etc.) and list of all the files contained on the tape. Floppy disks must be IBM DOS compatible format, and accompanied by documentation giving a list of all the files contained on the disk.

References: § 75.64(d)

Key Words: Reporting

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 14.11 RETIRED

Topic: Electronic Reporting

Question: What kinds of telecommunications are available for reporting? Can E-Mail be used?

Answer: In Phase I, utilities will have two telecommunications options available: asynchronous modem connection or INTERNET. Asynchronous modem connections can be made to perform the file transfer from PCS using EPA-provided ARBITER communications software and scripts. Larger computers connected to the INTERNET network may use the INTERNET File Transfer Protocol (FTP) to accomplish the file transfers. Although the EPA mainframe supports E-mail (as x.400 message passage over the INTERNET gateway), Phase I quarterly reports will not be accepted over E-mail.

References: § 75.64(d)

Key Words: Reporting

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 14.13 RETIRED

Topic: Operating Hours Definition

Question: Do "monitor operating hours" and "quality assured monitor operating hours" include hours when the unit is not operating?

Answer: No. Quality assured monitor operating hours that are used for calculations of availability and missing data substitution should be hours when the unit is operating. These would be the only hours of quality assured data that provide non-zero data.

References: § 75.10(d), § 72.2

Key Words: Missing data, Reporting

History: First published in November 1993, Update #2; retired in October 1999 Revised Manual

Question 14.14 RETIRED

Topic: Partial Unit Operating Hours

Question: How are emissions during partial unit operating hours accounted for? This is combustion time where the unit operates for some time in one or more, but not all four, parts of the clock hour.

Answer: To ensure that EPA's data calculation and reporting policies are consistent, this answer has been deleted. For more information on this topic, see Question 14.36 (Revised).

References: N/A

Key Words: N/A

History: First published in November 1993, Update #2; revised October 1996, Update #10; retired in October 1999 Revised Manual

Question 14.22 RETIRED

Topic: Quarterly Reporting -- Missing Operating Hour Information

Question: If a utility fails to report operating information for a unit or stack for certain hours in an operating quarter, what does EPA assume about emissions during these hours?

Answer: If a file for a quarter does not provide operating data in RT 300 for certain hours within the quarter, EPA will treat these missing hours as full operating hours and apply appropriate missing data procedures to calculate estimated emissions.

References: § 75.64

Key Words: Electronic report formats, Reporting

History: First published in November 1994, Update #4; retired in October 1999 Revised Manual

Question 14.23 RETIRED

Topic: Quarterly Reporting -- Missing Load Range Data in Record Types 300, 220 and 320

Question: If a RT 300 does not identify a load range for an operating hour, what default load range will EPA use for the hour?

Answer: If load range is missing (either from the reported RT 300 or because EPA "created" a RT 300 when there was no operating data reported for the hour), EPA will use a default load range of 10 (or 20 for common stacks, if appropriate) for all hours for which flow or NO_x emission rate is missing and missing data procedures will be used to determine the appropriate values to characterize emissions.

References: § 75.64

Key Words: Electronic report formats, Reporting

History: First published in November 1994, Update #4; retired in October 1999 Revised Manual

Question 14.25 RETIRED

Topic: Quarterly Reporting -- Missing or Invalid F-Factors

Question: How will EPA check the NO_x emission rate and heat input calculations if the F-factor is not reported in RT 320?

Answer: If the F-Factor is missing, EPA will use the F-Factor submitted in the relevant formula in Table C of the Monitoring Plan. If there is no F-Factor available in the monitoring plan formula, EPA will use the F-Factor in Appendix F § 3.3.5 Part 75 for the primary fuel for the unit or common stack.

References: § 75.64, App. F (3.3.5)

Key Words: Electronic report formats, F-Factors, Reporting

History: First published in November 1994, Update #4

Question 14.28 RETIRED

Topic: Quarterly Reporting -- Maximum Acceptable CO_2 and O_2 Values

Question: Is there a maximum CO_2 or O_2 % concentration value which EPA considers to be unacceptable?

Answer: EPA has established a limit of 20% for acceptable CO_2 or O_2 values. EPA will treat all values greater than 20% as missing data.

References: App. A, App. F

Key Words: Data validity, Reporting

History: First published in November 1994, Update #4; retired in October 1999 Revised Manual

Question 14.29 RETIRED

Topic: Performing DAHS Verifications for Multiple Units

Question: A utility company plans to upgrade their DAHS for all 16 units. They plan to use DCAS for all 16 units. Must the utility run DCAS for all 16 units individually or can they run DCAS on a central computer?

Answer: The utility must perform DAHS verification tests for each installation of software, not necessarily for each unit.

DCAS has three main steps:

Step 1) DCAS creates a historical test data set.

Step 2) The DAHS takes the test data set and fills in the missing data by calculating the substitute missing values.

Step 3) DCAS checks the answers on the test by comparing the current missing data values to the missing data values generated by the DAHS.

Step 2 must be performed where the DAHS software that performs missing data is installed. Steps 1 and 3, the comparison of criteria of test data and the two files, may be done on a central computer.

References: § 75.20(c)(7), § 75.63

Key Words: Certification tests, DAHS

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 14.34 RETIRED

Topic: Interim Reporting Requirements for Appendix E Units

Question: Since the new record types in EDR Version 1.3 are not required until January 1, 1996, what are the reporting requirements for an Appendix E unit that is required to complete certification testing by July 1, 1995?

Answer: Between July 1, 1995 and January 1, 1996, an appendix E unit must submit a quarterly report that contains the average NO_x emission rate for the quarter and the average NO_x emission rate year-to-date in RT 301. The average NO_x emissions should be determined using the estimation procedures outlined in Appendix E. Until January 1, 1996, the DAHS does not have to calculate this value or record the parameters used to calculate it. The parameters needed to calculate the average NO_x emissions can be recorded manually and the average NO_x emissions in RT 301 may be manually entered into the quarterly report.

Note that this does not exempt a utility from reporting the other required data in its quarterly report. This includes SO_2 data, CO_2 data and heat input data which may not be manually entered.

Also note that it is still necessary to perform the NO_x-load correlation testing required in Appendix E by July 1, 1995. However, it is not necessary to perform DAHS testing by July 1, 1995. This testing must be completed by January 1, 1996.

References: § 75.64, App. E, EDR VI.3

Key Words: DAHS, Electronic report formats, Excepted methods, NO_x monitoring, Reporting

History: First published in July 1995, Update #6; retired in October 1999 Revised Manual

Question 14.35 RETIRED

Topic: Reporting of Oil Sulfur Content

Question: In RT 313, how do I report the sulfur content of oil if I do daily manual sampling? Do I report the actual sulfur content for that day's sample, or do I report the highest sulfur content of the last 30 daily samples?

Answer: Report the actual sulfur content for that day's sample. However, when calculating SO_2 mass emissions, use the highest sulfur content of the last 30 daily samples.

References: App. D (2.2.4 and 3.1), § 75.51(c)(2), § 75.55(c)(2)

Key Words: Excepted methods, Fuel sampling, Reporting, SO_2 monitoring

History: First published in July 1995, Update #6; retired in October 1999 Revised Manual

Question 14.42 RETIRED

Topic: Reporting of Oil Sulfur Content

Question: In RT 321 and 323, when I report the sulfur content of oil, should I report it for 24 consecutive hours until the next sample is taken?

Answer: No. Report the sulfur content for each hour of a calendar day. This will allow greater flexibility for a utility if manual tests are performed slightly more or slightly less than 24 hours apart.

References: RT 321 and 323, App. D (2.2.3, 2.2.4 and 2.4.1)

Key Words: Excepted methods, Fuel sampling, Reporting, SO_2 monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.43 RETIRED

Topic: Reporting of SO_2 Emissions during Gas-Only Hours

Question: Policy Manual Question 2.6 (Revised) indicates that SO_2 emissions (lbs/hour) should be reported in RT 310 for the hours when only natural gas is combusted. However, RT 312 (and now RT 314) is used to report SO_2 emissions (lbs/hour) when the emissions are from natural gas or other gaseous fuels. Which approach is correct?

Answer: Use one of the following methods to record and report SO_2 mass emissions when combusting only natural gas, beginning no later than January 1, 1997. Either approach is correct for a unit combusting pipeline natural gas. A unit combusting gaseous fuels other than pipeline natural gas will use the Appendix D fuel sampling method.

(1) **Equation F-23**: RT 310 may be used by those utilities electing to determine heat input by using a CO_2 or O_2 monitor and a flow monitor, then using the conversion factor of 0.0006 lbs/mmBtu to convert to SO_2 emissions for pipeline natural gas. Report the formula ID associated with formula F-23 for that hour. You will need to report RT 202 or 211, 220, and 310. Because you do not report RT 200, no method of determination code is necessary for SO_2.

(2) **Appendix D Fuel Sampling Method**: RT 314 in conjunction with RT 303 may be used by those utilities electing to certify a fuel flow meter and use Appendix D fuel sampling and analysis in addition to using an SO_2 CEMS and a flow monitor. RT 312 may be used to report SO_2 until December 31, 1995 after which it will be superseded by RT 303 and 314 per EDR V1.3. Do not report RT 310 at the same time.

References: § 75.11(e), § 75.55(e), App. F (section 7)

Key Words: Electronic report formats, Reporting, SO_2 monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.45 RETIRED

Topic: Appendix D Reporting -- Fuel Flow Rate Source of Data

Question: There appears to be an inconsistency between the EDR V1.3 document and the CEMS Submission Instructions document. The problem is in the definition of valid values for the fields starting in RTs 302 and 303, column 31. Which document is correct?

Answer: Use the fuel flow rate source of data codes provided in the CEMS Submission Instructions document. The codes provided on pp. 3-54 and 3-55 contain the additional source of data codes for fuel flow rate that are alluded to in the EDR V1.3 document in footnote 4 for column 31 of RT 302. For example, in RT 302 for column 31, report "0" for a measured value from the fuel flow system, "1" for substitute data for the fuel flow system, or "3" for the maximum potential fuel flowrate.

References: CEMS Submission Instructions, pp. 3-54 and 3-55

Key Words: Electronic report formats, Excepted methods

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.50 RETIRED

Topic: Appendix D Reporting -- Emission Rate for Gas

Question: Previously, the EPA has directed us to use a default value of 0.0006 for NADB SO_2 rate. RT 314 now asks us to provide either the default rate or the one from NADB. Do we use and report the more conservative NADB rate, if it is available?

Answer: If you are combusting pipeline natural gas, use 0.0006 lb/mmBtu as the default SO_2 emission rate. Generally, if there were a more conservative NADB rate, it would be because the unit is combusting gaseous fuel other than pipeline natural gas or oil. If the unit is combusting gaseous fuel other than pipeline natural gas, then the unit is not eligible to use the default SO_2 emission rate and gas sampling and analysis is required.

References: CEMS Submission Instructions, p. 3-56, App. D (2.3)

Key Words: Excepted methods, Reporting, SO_2 monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.55 RETIRED

Topic: Monitoring Plans -- Electronic Report Formats

Question: The new form "Table A" does not support RT 502. Is there a new "draft" form coming?

Answer: There are no plans to change the Table A form. The three items not included in Table A, but included in RT 502 are:

(1) Maximum hourly gross load in megawatts (used for load range calculations)

(2) Maximum hourly gross steam load (used for load range calculations)

(3) Unit definition change date

References: § 75.64, EDR V1.3

Key Words: Electronic report formats, Monitoring plan

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.56 RETIRED

Topic: Monitoring Plans -- Electronic Reporting of Formulas

Question: Inclusion of quarterly and annual-to-date emission formulas is now optional in Table C. What would ETS do if the equations were still reported electronically?

Answer: You are not required to report these formulas electronically, however ETS-PC will check them for the required EDR format for RT 520 (Formula Table).

References: § 75.64

Key Words: Electronic report formats, Monitoring plans

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.57 RETIRED

Topic: Monitoring Plans -- Electronic Report Formats

Question: Should the Unit Definition Change Date field in RT 502 be blank unless changes are made to the boiler type, primary fuel, control types or monitoring approaches?

Answer: Effective January 1, 1996 RT 502 will supersede RT 500. The Unit Definition Change Date should be left blank unless subsequent changes are made to the boiler type, primary fuel, control type or monitoring approach.

References: § 75.64, EDR V1.3

Key Words: Electronic report formats, Monitoring plan

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.59 RETIRED

Topic: Reporting of Stack Testers Data

Question: Record Types 612 (Reference Method Support Data for Gas RATAs) and 613 (Reference Method 2 Supporting Data for Flow RATAs) are required on January 1, 1998, and list a large number of parameters from the stack testers. Nearly all of the data required for these record types can only be hand entered. Can the data be hand entered into our DAHS or can it be electronically uploaded from our stack testing teams after they have hand entered the data to prepare the file for uploading?

Answer: The EPA acknowledges that some of the data to be reported in RTs 612 and 613 may be recorded manually and thus manually entered into the DAHS. The EPA does encourage the electronic capture of stack testing data and thus an electronic merge of these data with all of the other data already contained in the DAHS.

References: CEM Submission Instructions, pp. 3-50 and 3-51

Key Words: DAHS, Data reduction, Reporting, Stack testing

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.67 RETIRED

Topic: Data Editing

Question: Under "Data Editing" on p. 3-16 of the CEM Submission Instructions, it states: "it is acceptable to replace invalid data with either back up monitor data or missing data substitution.

Please note that the DR must submit a RT 555 in the quarterly report to provide documentation of the reason for these replacements and associated corrective actions with the quarterly compliance statement."

On p. 3-25, RT 555 is defined as "Monitoring System Recertification Events." Using data from a certified back up onitor or missing data substitution does not fit the definition of a recertification event for RT 555. We believe missing data substitution events should be addressed in RT 550, Monitoring System Missing Data Reasons, and events that involve using data from certified back up monitors do not belong in RT 550 or 555. Does the Agency agree?

Answer: Yes. The phrase "RT 555" contained in the second paragraph of the CEMS Instructions 3-16 should be changed to read "RT 550." RT 550 must only be submitted when missing data are used during a quarter.

Utilities are not required to submit RT 555 except for significant changes to any monitoring system(s) which require recertification.

References: CEM Submission Instructions, pp. 3-16 and 3-26, Policy Manual Question 14.61

Key Words: Backup monitoring, Electronic report formats, Missing data, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.68 RETIRED

Topic: Use of RT 550 for Appendix G

Question: Would RT 550 records be required in the event of missing lab analysis data for an Appendix G CO_2 mass emission calculation if it is used as the primary means of determination? What if Appendix G is only used for missing data substitution?

Answer: No. RT 550 records are not required in the event of missing lab analysis data for an Appendix G CO_2 mass emission calculation, either for Appendix G as the primary means of CO_2 determination or as a means of substituting data from a CO_2 CEMS. If Appendix G is being used to substitute for CO_2 concentration data from a CEMS, simply report a single RT 550 for missing data from the CO_2 CEMS.

References: App. G, EDR V1.3

Key Words: CO_2 monitoring, Electronic report formats, Fuel sampling, Missing data

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.70 RETIRED

Topic: RT 550 for Appendix D

Question: If an oil-burning unit that measures oil in volumetric units reports an RT 550 record for "OILV", should another RT 550 record be reported for "OILM" since it would also be missing?

Answer: No. It is not necessary to report an additional RT 550 for "OILM." Although it is true that this value will also be missing, the certified oil flow measurement system is "OILV."

If you are using a volumetric oil flowmeter, report one RT 550 for the parameter "OILV" in column 10 of RT 550. If you are using a mass oil flowmeter, report one RT 550 for the parameter "OILM" in column 10.

References: § 75.64, EDR V1.3

Key Words: Electronic report formats, Fuel sampling, Missing data, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.71 RETIRED

Topic: RT 550 for Appendix D

Question: How do I report RT 550 if I am missing lab analysis data, such as GCVG, GCVO, %SO, %SG, or DENS?

Answer: It is not required to report RT 550. This answer supersedes CEMS Submission Instructions p. 3-26 ("You must also submit an RT 550 for missing GCV% sulfur or oil density under Appendix D."). Record Types 302 and 303 already indicate which parameter is missing and EPA assumes this is because of missing lab analysis data. If you choose to report RT 550 for missing lab analysis data, follow the guidance in the Submission Instructions p. 3-26.

References: § 75.64, EDR V1.3, CEM Submission Instructions p. 3-26

Key Words: Electronic report formats, Fuel sampling, Missing data, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.74 RETIRED

Topic: NO_x Emission Rate Reporting

Question: In RT 323, there are fields to enter an average NO_x emission rate for the hour (combined fuels), an average NO_x emission rate for the hour for oil and an average NO_x emission rate for the hour for gas. How should these fields be used if a unit is only burning one type of fuel, if it is co-firing oil and gas and if it is co-firing multiple types of oil?

Answer: Because of the complications that can arise when a unit is firing multiple types of fuel, EPA is only requiring that the field for "average NO_x emission rate for the hour (combined fuels)" be used. If a unit if burning one type of fuel, this column should contain the NO_x emission rate from the most recent correlation curve for that unit. If a unit is burning multiple fuels this column should contain an average NO_x emission rate calculated using Equation E-2. The EPA will disregard any values reported in the fields for "Average NO_x emission rate for the hour for gas" even though it is permissible for the utility to report these values.

References: RT 323, App. E

Key Words: NO_x monitoring, Reporting

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 14.76 RETIRED

Topic: Record Type 101

Question: Is Record Type 101 required or optional?

Answer: Until further notice, RT 101 may be considered optional.

References: EDR V1.3

Key Words: Electronic report formats, Reporting

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 14.77 RETIRED

Topic: Recertification Requirements for Installation of EDR V1.3 Software

Question: At EPA's August 1995 conference, EPA appeared to state that units with CEMS that install software that incorporates the new electronic data reporting format version 1.3 (EDR V1.3) are not required to perform missing data or formula verification. Is that correct?

Answer: Yes. If the only thing you are doing is switching versions to implement the requirements of EDR V1.3, then it is not necessary to perform formula verification or missing data testing. However, if the missing data procedures or formulas were revised during the upgrade, then the applicable software recertification test must be performed. Therefore, many Appendix D units that are implementing revised missing data procedures will have to perform missing data verification. Also, although EPA does not require you to perform missing data or formula verification testing, EPA recommends that you perform these tests for your own purposes to ensure that no unintended changes were made to the software.

Note that if a utility is switching to new software from a new vendor, it will be necessary to recertify, including DCAS, formula verification testing and certification statements from the designated representative.

References: EDR V1.3

Key Words: DAHS, Electronic report formats, Recertification

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 14.78 RETIRED

Topic: CO_2 Emissions Reporting

Question: There appears to be an inconsistency in the use of the method of determination code for CO_2 emissions reported in RT 330 when Appendix G fuel sampling procedures are used. The May 1995 Acid Rain Program CEMS Submission Instructions say to use "13" and in the May 17, 1995 regulation there is a new method code 15 in § 75.54, Table 4. How should method code 13 and method code 15 be used?

Answer: These two codes were switched in the rule due to a typographical error. If you have already programmed "13" to report CO_2 mass emissions from fuel sampling and analysis, continue using the method of determination code of "13". Use a method of determination code of "15" for "Other" methods of determination.

If you have already programmed the method of determination code of "15" to report CO_2 mass emissions from fuel sampling and analysis, this is also acceptable. EPA intends to correct this in the Federal Register in the future. As of January 1, 1999, the correct method of determination codes will be "13" to report CO_2 mass emissions from fuel sampling and analysis, and "15" for "Other" methods of determination. However, you may continue to use the method of determination code that is currently programmed in your DAHS through December 31, 1998.

References: § 75.54, App. G, EDR V1.3

Key Words: CO_2 monitoring, Electronic report formats, Reporting

History: First published in March 1996, Update #8; revised June 1996, Update #9; retired in October 1999 Revised Manual

Question 14.79 RETIRED

Topic: Deadline for Reporting in EDR Version 1.3

Question: My company is currently in the process of upgrading its software so that we can report using EDR V1.3. We have been making our best efforts to upgrade the software in time to submit our first quarter 1996 report in EDR V1.3 by April 30, 1996. However, we are not sure if we will be able to upgrade the software in time at every single unit. Should we petition the Agency for an extension for each unit where we do not make the software change to report using EDR V1.3 in time for our first quarter

1996 report? Should we resubmit the first quarter 1996 report in EDR V1.3 as soon as we have made the change?

Answer: No. If you are in this situation, the Agency will allow you to submit the first quarter 1996 report with your old version of software, provided that you submit your second quarter report for the unit in EDR V1.3 by July 30, 1996. Rather than petitioning the Agency, you must state in the cover letter for the first quarter 1996 report for each unit using this deadline extension that you reported the file in EDR V1.1 (or V1.2), rather than in EDR V1.3, and that the second quarter 1996 report will be in EDR V1.3.

When a unit uses the extension, do not resubmit the first quarter 1996 report in EDR V1.3. The requirement to submit the second quarter 1996 report in EDR V1.3 will be subject to EPA enforcement action, where appropriate.

References: §§ 75.54, 75.64(a)(1)

Key Words: Deadlines, Electronic report formats

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 14.83 RETIRED

Topic: Calculation of Hourly Emission Rates

Question: The units for hourly NO_x emission rate (data element in columns 36 to 41 of RT 320 in EDR V1.3) are defined as lb/mmBtu/hr. In Part 75, subpart F, the units for hourly NO_x emission rate are defined as lb/mmBtu. Which is correct?

Answer: The correct units for reporting hourly average NO_x emission rate are lb/mmBtu. The lb/mmBtu/hr units defined for NO_x emission rate in RT 320 of EDR V1.3 are incorrect.

References: § 75.54(d), App. F

Key Words: NO_x emission rates, Reporting

History: First published in October 1996, Update #10; retired in October 1999 Revised Manual

Question 15.11 **RETIRED**

Topic: Appendix D and E Missing Data Procedures

Question: If I have previously certified my Appendix D or E DAHS under the old rule must I recertify it?

Answer: Yes. All units that use Appendix D and E must complete either an initial certification or a recertification, which demonstrates they meet the requirements in Question 15.12 before the 1st Quarter 1996 report is submitted. The 1st quarter 1996 report must be submitted in EDR Version 1.3 format and must use the missing data procedures specified in the direct final rule published May 17, 1995.

References: App. D and E

Key Words: DAHS, Excepted methods, Missing data, NO_x monitoring, SO_2 monitoring

History: First published in July 1995, Update #6; retired in October 1999 Revised Manual

Question 15.15 **RETIRED**

Topic: Appropriate Procedures for Infrequently Operated Bypass Stack

Question: A unit emits through a bypass stack for less than 720 hours in a three year period (for example, 70 hours of bypass operation from April 1, 1997 to April 1, 2000). Does the utility continue to implement the standard missing data procedures, or does the utility instead implement the initial missing data procedures?

Answer: The standard missing data procedures, provided that more than 720 quality-assured monitor operating hours of SO_2 concentration data or 2160 quality-assured monitor operating hours of flow rate or NO_x data have passed since initial certification. If less than 720 quality assured monitor operating hours of SO_2 concentration data or 2160 quality assured monitor operating hours of flow rate or NO_x data have been collected since initial certification use the initial missing data procedures.

References: § 75.32, § 75.33(a)

Key Words: Missing data

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 15.18 RETIRED

Topic: Appendix D Missing Data Procedures -- GCV and Density

Question: Unlike the missing data procedures for % sulfur, there is no mention of using a maximum GCV value if no data are available. If this is required, what are the rules for determining it? Can it be dynamically tracked?

Answer: If no GCV data at all are available so that there is no historical GCV information, use the maximum GCV value, as indicated by information from your fuel supplier. Once GCV or density data are available, follow the missing data procedures in section 2.4 of Appendix D using as many samples as are available until 30 are available.

References: App. D (2.4)

Key Words: Excepted methods, Missing data, SO_2 monitoring

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 15.25 RETIRED

Topic: Missing Data Procedures for Gas GCV

Question: Regarding the new missing data procedures for gas GCV: if our software is designed to use a default value, which is the latest entry off the gas contract, and the QA/QC plan ensures that this value is updated at least once per month, there will never be a missing data period. Would the supplemental DCAS test we provide still have to show that a missing data procedure is programmed even if it will never be used?

Answer: Yes. The supplemental DCAS test should indicate that missing data procedures are programmed into the DAHS.

References: § 75.20

Key Words: DAHS, Gas-fired units, Missing data

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 15.27 RETIRED

Topic: Missed QA/QC Test -- RATA

Question: A utility was unable to perform a RATA in the quarter it was required. Must a utility immediately begin to report using substitute data in the next quarter?

Answer: No, EPA recognizes that there are times that a RATA deadline may be missed due to circumstances beyond a utility's control. Therefore, effective January 1, 1997, EPA will allow the utility to use up to 336 unit operating hours of the CEM data as valid data instead of using substitute data if the utility adheres to the following procedures:

1. If the "make-up" RATA for the previous calendar quarter is not completed within 336 unit operating hours, then the utility must report substitute data , beginning with the 337th unit operating hour in the quarter, and continuing until the monitor passes a RATA.

2. In the quarterly report cover letter or in RT 910, the utility provides the following information:

   ! Original RATA deadline
   ! Reason test was missed
   ! Original date for which RATA was scheduled
   ! Number of unit operating hours before RATA was completed in current quarter

3. Regardless of the number of RATA attempts performed in the quarter of the grace period (e.g., to achieve a better relative accuracy or BAF), the utility determines the deadline for the next annual or semi-annual RATA based on the quarter in which the original RATA was to have been performed.

References: App. B (2.3.1), § 75.30, § 72.2

Key Words: Deadlines, Missing data, RATAs

History: First published in March 1997, Update #11; retired in October 1999 Revised Manual

Question 16.1A RETIRED

Topic: Missing Data Procedures for Scrubbers

Question: In the CEMS Submission Instructions, section 3, page 3-5, it states that if you operate a scrubber and you use standard missing data procedures, "you must certify that the control equipment was operating properly and that you have information documenting their operational status for each hour of missing data." Please explain in detail the documentation that is required to be maintained on-site.

Answer: The source must maintain the documentation required in the general recordkeeping provisions under § 75.51(b) or 75.55(b) before January 1, 1996. After January 1, 1996 the source must maintain the documentation required under § 75.55(b).

References: §§ 75.51 and 75.55, CEMS Submission Instructions, p. 3-5

Key Words: Missing data, Recordkeeping, Scrubbers

History: First published in November 1995, Update #7; retired in October 1999 Revised Manual

Question 16.5 RETIRED

Topic: Missing Data Requirements for SO_2 Inlet and Outlet Systems

Question: Record Types 420 and 421 of the draft EDR V1.2 list 01-04 as the acceptable range for method of determination codes for SO_2/diluent inlet and outlet monitoring systems installed on Phase I Qualifying Technology facilities. Does this indicate that "missing data" procedures do not apply to the SO_2/diluent systems?

Answer: Yes. The 90% SO_2 removal demonstration is to be based on quality-assured CEM data, <u>only</u> (see § 75.15(b)(3)). Missing data routines do not apply to these monitoring systems.

References: EDR V1.2, § 75.15(b)(3)

Key Words: Control devices, Electronic report formats, Missing data, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 16.6 RETIRED

Topic: Bias Adjustment Factors -- Requirements for SO_2 Inlet/Outlet Systems

Question: Do "bias adjustment factors" apply to the SO_2/diluent monitoring systems required for Phase I Qualifying Technology sources?

Answer: No. Section 75.20(c)(5) does not require a bias test for SO_2/diluent monitoring systems. The lb/mmBtu SO_2 data from these monitoring systems are used to derive a relative measure of SO_2 removal efficiency by comparing SO_2 outlet measurements relative to SO_2 inlet measurements. The data from these systems are not associated with the allowance accounting system, nor are the data referenced to an emission limit (as are NO_x lb/mmBtu data). Therefore, "system" bias adjustment factors, analogous to NO_x system bias adjustment factors, are not applied to the lb/mmBtu SO_2 data from the inlet and outlet SO_2/diluent monitoring systems. However, if the SO_2 component of the outlet SO_2/diluent system also serves as the SO_2 pollutant concentration system for Part 75 allowance accounting purposes, the SO_2 system on a ppm basis, must undergo a bias test and may have a bias adjustment factor.

References: § 75.20(c)(5)

Key Words: Bias, Control devices

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 16.7 RETIRED

Topic: Reporting Requirements for SO_2 Inlet and Outlet Systems

Question: Must daily calibration and other quality-assurance records be submitted in EDR format for Phase I qualifying inlet and outlet SO_2-diluent monitoring systems? Also, must the inlet and outlet SO_2 and diluent concentration data be reported under the SO_2-

diluent monitoring system ID numbers on an hourly basis in RTs 200 and 210 (or 211) of the EDR?

Answer: The inlet and outlet SO_2-diluent monitoring systems are subject to the quality assurance requirements of Appendix B, including daily calibration error tests, linearity tests and RATAs. Therefore, these results must be reported in the EDR in RTs 230, 601, 602, 610 and 611. Note, however, that for the outlet SO_2-diluent system, the daily calibration and linearity data need not be reported more than once if the same CO_2 or O_2 monitor is used as a diluent monitor in both the outlet SO_2-diluent system and the outlet NO_x-diluent system, and/or when the SO_2 pollutant concentration monitor used for lb/hr SO_2 reporting is also used for outlet lb/mmBtu SO_2 reporting. In such instances, it is sufficient to report the daily calibrations and linearity results for the diluent component of the outlet SO_2-diluent system under the NO_x-diluent system ID number and to report the daily calibration and linearity test results for the SO_2 component of the outlet SO_2-diluent system under the SO_2 pollutant concentration monitoring system ID number.

Regarding the reporting of the individual SO_2 and diluent concentration data streams, § 75.55(a) requires only that the inlet and outlet SO_2 emission rates (in lb/mmBtu) be reported, not the SO_2 and diluent concentration data. Therefore, RTs 200 and 210 (or 211) do not have to be reported under the SO_2-diluent monitoring system ID numbers. Only RTs 420 and 421 are required. Keep the hourly inlet and outlet SO_2 and diluent data on-site, in an accessible format, suitable for auditing purposes.

References: § 75.51(e), § 75.55(a), § 75.64(a)(1), App. B

Key Words: Calibration error, Control devices, Quality assurance, Reporting

History: First published in March 1995, Update #5; revised October 1996, Update #10; retired in October 1999 Revised Manual

Question 16.8 RETIRED

Topic: SO_2 Inlet Monitoring in Multiple Ducts or Stacks

Question: I have a Phase I Qualifying Technology affected unit that has dual breechings at the inlet to the scrubber, and each breeching is equipped with a SO_2/diluent CEMS. Is it permissible to designate the SO_2/diluent system in one duct as the primary system and the other as a redundant backup system, or must the inlet SO_2 emission rate in lb/mmBtu be reported as an average of the emission rates in the two ducts?

Answer: Monitoring the SO_2 lb/mmBtu emission rate in one of the two breechings is acceptable provided that the products of combustion in the two ducts are thoroughly mixed and the inlet systems are before <u>all</u> SO_2 controls. It is necessary to measure in both ducts if the products of combustion may not be thoroughly mixed in both ducts. If it is necessary to measure in both ducts, define in your monitoring plan separate ducts using "MS" stack IDs and report separate records of the hourly SO_2 inlet emission rate in RT 420 in each duct for each hour using the multiple stack ID. Report the average emission inlet rate for the unit on an hourly basis in RT 420. Leave the monitoring system ID blank in RT 420 when more than one system is used to calculate the hourly rate.

References: § 75.15

Key Words: Control devices, Electronic report formats, Multiple stacks, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 16.9 RETIRED

Topic: Required Data Availability for SO_2 Inlet and Outlet Systems

Question: Part 75 does not specify a minimum required percentage data availability for the SO_2/diluent monitoring systems installed on the inlets and outlets of Phase I qualifying Technology affected units. What percentage monitor availability does EPA consider sufficient to provide a credible demonstration of the required 90% SO_2 removal efficiency?

Answer: EPA considers 90.0% data availability to be both appropriate and attainable for the required inlet and outlet SO_2/diluent monitoring systems. That is, for each calendar year of the demonstration of percentage SO_2 removal efficiency, EPA expects the percentage availability of each SO_2/diluent system to be maintained at or above 90.0%. Percentage availability is calculated in accordance with § 75.32.

References: § 75.15, § 75.32

Key Words: Control devices, Missing data, Reporting

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 16.11 RETIRED

Topic: Certification Tests for SO_2-diluent CEMS on Phase I Qualifying Technologies

Question: What certification tests are necessary for SO_2-diluent CEMS on units with a Phase I qualifying technology?

Answer: The following certification tests are necessary for each inlet and each outlet SO_2-diluent CEMS:

(1) a 7-day calibration error test for both the SO_2 and the diluent components of the CEMS;

(2) a linearity check for both the SO_2 and the diluent components of the CEMS;

(3) a RATA for the SO_2-diluent CEMS in lb/mmBtu, but no bias test;

(4) a cycle test for both the SO_2 and the diluent components of the CEMS; report the longer cycle time of the SO_2 and the diluent components of the CEMS; and

(5) formula verification for the DAHS of the formula for SO_2 lb/mmBtu, including a DR certification statement for production of quarterly reports.

No bias test or missing data verification test is necessary for the SO_2-diluent CEMS.

Note that the certification deadline for SO_2-diluent monitoring systems is January 1, 1997. Utilities may certify their monitors before the January 1, 1997 deadline and report inlet and outlet SO_2 lb/mmBtu data in RTs 420 and 421 if they wish, in order to practice submitting these data before data submittal is required beginning with the first quarterly report for 1997.

References: § 75.15, § 75.20(c)(5)

Key Words: Certification tests, Phase I qualifying technology, SO_2 monitoring

History: First published in October 1996, Update #10; retired in October 1999 Revised Manual

Question 16.12 RETIRED

Topic: Certification Tests for SO_2-diluent CEMS on Phase I Qualifying Technologies

Question: A utility has a Phase I qualifying technology installed on one of its units. It is now preparing to certify its SO_2-diluent monitoring systems. May the utility use historical test data, or must it perform a special set of certification tests for each SO_2-diluent system?

Answer: For the outlet SO_2-diluent system, the utility may use historical test data, provided that:

(1) both the SO_2 and diluent components have been previously certified under Part 75;

(2) both have been meeting the quality-assurance testing requirements in Appendix B of Part 75; and

(3) the historical RATA data for the SO_2 and diluent components are from concurrent testing.

If, for example, the required SO_2-diluent system consists of the primary SO_2 pollutant concentration monitor and the diluent monitor from the primary NO_x monitoring system, then no additional certification tests are required to be performed (except as described below).

The utility should use the most current data available to certify the SO_2-diluent system. For example, use the most recent quarter's linearity check results; seven recent days of daily calibration error test results, during which no maintenance was performed and no adjustments were made other than routine calibration error adjustments, for the seven-day calibration error tests; the cycle time test results from initial certification (unless this test has been repeated since initial certification); and the most recent concurrent RATA test data for the SO_2 and diluent component monitors, recalculated to provide the relative accuracy of the SO_2-diluent system on a lb/mmBtu basis. Note, however, that a new test is required for formula verification of the DAHS, since there is a new formula for calculating SO_2 lb/mmBtu. Additionally, if the recalculated relative accuracy (RA) of the SO_2-diluent system on a lb/mmBtu basis is either:

(1) RA > 10.0%; or

(2) 7.5% < RA $\leq$ 10.0% and more than two calendar quarters have elapsed since the quarter in which the test was conducted,

then it will be necessary to conduct an additional relative accuracy test for the SO_2-diluent system on a lb/mmBtu basis for certification.

For the inlet SO_2-diluent system, presumably no tests have been performed previously; therefore, a new set of certification tests is necessary.

Submit a complete certification application for the inlet and outlet SO_2-diluent monitoring systems to the appropriate State and Regional EPA offices. Both hard-copy and electronic submittals are required. In addition, submit a copy of the certification diskette to the Acid Rain Division, addressed to the attention of Kim Nguyen.

References: § 75.15, § 75.20

Key Words: Certification tests, Phase I qualifying technology, SO_2 monitoring

History: First published in October 1996, Update #10; retired in October 1999 Revised Manual

Question 16.13 RETIRED

Topic: Monitoring Plan for SO_2-diluent CEMS on Phase I Qualifying Technologies

Question: A utility has a Phase I qualifying technology installed on one of its units. It is now preparing to submit a monitoring plan for SO_2-diluent systems at the unit inlet and on the unit stack. How should these systems be represented in the monitoring plan for the unit?

Answer: SO_2 monitoring systems for measuring lb/mmBtu for Phase I qualifying technologies should look similar to monitoring systems for NO_x in lb/mmBtu in the monitoring plan, and should follow the guidelines set out below.

(1) Table B. For the outlet SO_2-diluent system, the utility should add a new primary system containing an SO_2 analyzer component, a CO_2 or O_2 analyzer component, and a DAHS. The new outlet system should have a new system identification number and should have a system parameter of "SOO" (SO_2 outlet) for all three components in the system. The utility should reuse the component identification numbers for any components that are already installed on the stack. For example, if the SO_2-diluent system consists of the primary SO_2 pollutant concentration monitor and the diluent monitor from the primary NO_x system, the component ID numbers of these monitors should be used, along with a new system ID.

For the inlet SO_2-diluent system, the utility should add a new primary system containing an SO_2 analyzer component, a CO_2 or O_2 analyzer component, and a DAHS. The new inlet system should have a new system identification number and should have a system parameter of "SOI" (SO_2 inlet) for all three components in the system. The utility will also need to add new component identification numbers for all three components.

(2) Table C. Provide an equation for calculating SO_2 lb/mmBtu for each SO_2-diluent monitoring system. Identify in these equations each system and component ID in place of the variables for pollutant and diluent concentration, as you would for a NO_x-diluent CEMS. The formula parameter (column 3 in Table C of the monitoring plan) for both inlet and outlet SO_2 emission rate formulas in lb/mmBtu is "SO2R". Appropriate formula codes from Method 19 of Appendix A, Part 60 to put in column 4 of Table C are: 19-7 (both SO_2 and CO_2 diluent monitors on wet basis), 19-8 (SO_2 monitor on wet basis, CO_2 diluent monitor on dry basis), 19-9 (SO_2 monitor on dry basis, CO_2 diluent monitor on wet basis), 19-6 (both SO_2 and CO_2 diluent monitors on dry basis), 19-3 (both SO_2 and O_2 diluent monitors on wet basis), 19-4 (SO_2 monitor on wet basis, O_2 diluent monitor on dry basis), 19-5 (SO_2 monitor on dry basis, O_2 diluent monitor on wet basis) or 19-1 (both SO_2 and O_2 diluent monitors on dry basis).

References: § 75.15, § 75.53, 40 CFR Part 60, App. A (RM 19)

Key Words: Monitoring plans, Phase I qualifying technology, SO_2 monitoring

History: First published in October 1996, Update #10; retired in October 1999 Revised Manual

Question 17.4 RETIRED

Topic: Common Stack -- NO_x Monitoring

Question: We have two coal-fired units that are tangentially-fired boilers exhausting to a common stack. One unit is a transfer unit and will not have a NO_x emission limitation until 1997. The other unit is a substitution unit and will have a NO_x emission limitation. It will be relatively infrequent that the two units will operate simultaneously. Can we simply monitor the common stack for NO_x?

Answer: No. 40 CFR 75.17(a)(3) states that in this situation, the owner or operator shall either:

(A) Install, certify, operate, and maintain NO_x and diluent monitors in the ducts from the affected units; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack on each of the units. The Administrator may approve such demonstrated substitute methods for apportioning NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under Part 75.

The NO_x emission rate measured in the common stack could potentially underestimate the NO_x emission rate of the substitution unit that has a NO_x emission limitation if the unit with no limitation has a lower emission rate.

References: § 75.17(a)(3)

Key Words: Common stack

History: First published in May 1993, Update #1; retired in October 1999 Revised Manual

Question 18.2 RETIRED

Topic: "K" Constant for Conversion to NO_x Emission Rate

Question: Should we use a conversion factor of 1.19×10^{-7} (lb/scf)/ppm or $1.19\underline{4} \times 10^{-7}$ (lb/scf)/ppm to convert NO_x concentration in ppm and diluent gas concentration in $\%CO_2$ or O_2 to NO_x lb/mmBtu?

Answer: Use 1.194×10^{-7} (lb/scf)/ppm, the more precise conversion factor, in your software. However, if you have already submitted certification test results using 1.19×10^{-7} (lb/scf)/ppm, you do <u>not</u> need to revise the test results. Future updates of your monitoring plan should reflect the use of 1.194×10^{-7} (lb/scf)/ppm.

References: App. A (7.4.1), App. F (3.2 and 3.3)

Key Words: Certification process, Conversion procedures, Monitoring plan

History: First published in November 1993, Update #2; revised July 1995, Update #6; retired in October 1999 Revised Manual

Question 18.3 RETIRED

Topic: F-factor Apportionment for Multiple Fuel Hours

Question: A utility has two units sharing a common stack and can co-fire coal and natural gas in one of the two units. The utility currently is using its electrical generation in MW-hr to apportion its heat input from its monitoring systems on the common stack. Is the utility required to use different F-factors for each unit in its heat input apportionment, or may it use just a single F-factor prorated for each fuel at the common stack?

Answer: The utility may use a single F-factor for its heat input apportionment, provided that both units are of the same phase and have the same NO_x emission limitation. However, if the units are of different phases or have different NO_x emission limitations, the heat input apportionment should account for different F-factors at each unit based upon the fuel or fuels used by each unit. This may be done using the following equation:

$$HI_i = \left(\frac{Q \ x \ \%CO_2}{F_c \ x \ 100} \right) \left[\frac{F_{ci} \ MW_i}{\sum_{i=1}^{n} F_{ci} \ MW_i} \right]$$

Where:

HI_i	=	Heat input from a single unit
$(Q \text{ x } \%CO_2)/(F_c \text{ x } 100)$	=	Heat input from the flow monitor and CO_2 monitor at the common stack, using F_c-factor prorated for each fuel by heat input
F_{ci}	=	Carbon-based F-factor for fuels combusted at a particular unit
MW_i	=	Gross electrical output in MWe for a particular unit
n	=	Total number of units using the common stack
i	=	Designation of a particular unit

Steam flow may also be used as a measure of load, as described in Question 17.5.

This will allow EPA to determine compliance and NO_x emission penalties for each unit. However, a designated representative may also petition for other heat input apportionment methods.

References: App. F (3.3.5 and 3.3.6.4)

Key Words: Common stack, Conversion procedures, F-factors, NO_x monitoring

History: First published in March 1995, Update #5; retired in October 1999 Revised Manual

Question 33.1 RETIRED

Topic: Phase II, Group 1 Boilers

Question: Can an owner or operator of a Phase II, Group 1 boiler enter into a contract for low NO_x burners before knowing what the Phase II limits are and apply for an AEL demonstration, notwithstanding the provisions that the technology must be "designed to meet the limit?"

Response: EPA will consider an application in which an utility establishes all of the following:

(1) An owner or operator of a Phase II, Group 1 boiler installed a state-of-the-art, latest generation low NO_x burner (LNB) system before the January 19, 1996 revisions to the Phase II, Group 1 NO_x emission limits were proposed; and

(2) This LNB system is designed to meet the Phase II, Group 1 emission limit (0.5 lb/mmBtu for dry bottom wall-fired and 0.45 lb/mmBtu for tangentially fired boilers) applicable prior to finalization of revisions to the limits; and

(3) The requirements in 40 CFR 76.10 are met.

References: § 76.10

Key Words: Alternative emission limits, Phase II boiler

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 33.2 RETIRED

Topic: Boilers with Low NO_x Burners and Overfire Air

Question: A utility has installed low NO_x burners (LNBs) and overfire air (OFA) in reliance on either the rules proposed in November 1992 or the rules promulgated in March 1994. In light of the D.C. Circuit Court decision, can that utility plug up the OFA ports and apply for an AEL if it is experiencing operational problems due to the OFA?

Response: Under 40 CFR 76.10 (a)(2), in order to qualify for an AEL, a boiler must have installed the appropriate NO_x control system designed to meet the applicable emission limit under 40 CFR 76.5, 76.6, or 76.7. If a boiler installs an LNB plus OFA system, and the vendor guarantees were based on this system, then removal of the OFA would change the configuration of the original system and thereby invalidate any guarantees. The resulting changed NO_x control system would not be "designed to meet the applicable emission limit," and the applicant would not have demonstrated that the unit "cannot meet the applicable limitation using low NO_x burner technology" under section 407(d) of the Act. Therefore, the boiler would not qualify for an AEL demonstration period.

However, EPA will consider an application in which the utility establishes all of the following:

(1) The utility solicited bids for a LNB and a LNB plus OFA system, designed to meet the applicable emission limit, in the time period beginning November 24, 1992 (date of proposed Title IV Phase I NO_x rule) and ending November 29, 1994 (date of D.C. Circuit Court of Appeal's vacating of final Title IV, Phase I NO_x rule);

(2) It described in its solicitation the range of operating conditions (including fuel supply and load dispatch pattern) that it expected to experience while operating to comply with the applicable emission limit;

(3) It received three or more bids from reputable, nationally recognized vendors for LNB and LNB plus OFA systems that identify the lowest emission rate that could be achieved with their equipment;

(4) None of the identified emission rates in (3) for LNB were equal to or less than the applicable emission limit;

(5) During the period from November 24, 1992 until November 29, 1994, the utility installed a LNB plus OFA system, available for purchase in (3), that would produce the lowest emission rate among the emission rates identified in (3);

(6) It operated the LNB plus OFA system to produce the lowest emission rate identified with this control equipment in (3) and the operating conditions were within the range of conditions in (2);

(7) It experienced catastrophic problem(s) due to operation of LNB plus OFA system in (6);

(8) It optimized combustion on the boiler, using established techniques (e.g., GNOCIS, Ultramax, etc.), to comply with the applicable emission limit and eliminate the catastrophic problem(s);

(9) Its efforts in (8) were unsuccessful in eliminating the catastrophic problem(s);

(10) The utility plugged up the OFA ports to the extent necessary to eliminate the catastrophic problem(s) that it had continued to experience;

(11) As a result of its action(s) in (10), the utility stopped complying with the applicable emission limit; and

(12) The requirements in 40 CFR 76.10 are satisfied.

References: § 76.10

Key Words: Alternative emission limits, Overfire air

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 33.5 RETIRED

Topic: Availability of AEL for Boilers that Retrofit LNBs before Part 76 Requirements Became Effective

Question: Under what circumstances can the owner or operator of a Phase I, Group 1 boiler that retrofit low NO_x burners before the November 15, 1990, enactment of the CAA Amendments apply for and receive an AEL using those low NO_x burners? What if low NO_x burners were retrofit after 1990 but before part 76 was issued on April 13, 1995?

Answer: The owner or operator of a Phase I, Group 1 boiler that installed an LNB system prior to April 13, 1995, may qualify for an AEL demonstration period if the LNB system was designed to meet a NO_x emission rate equal to the applicable Phase I, Group 1 emission limit.

References: § 76.10

Key Words: Alternative emission limits, LNB

History: First published in March 1996, Update #8; retired in October 1999 Revised Manual

Question 34.1 RETIRED

Topic: Common Stack Monitoring Considerations

Question: A utility has several Phase II units using a common stack. The utility is considering the option of early election for these Phase II units. What are the NO_x monitoring options for the units? In particular, when may the utility use just a single NO_x CEMS on the common stack?

Response: In all cases, it is acceptable for the early election units to be monitored individually for NO_x emission rate in lb/mmBtu under 40 CFR 75.17(a)(1), (a)(2)(iii)(A) or (b)(1). Each NO_x CEMS must include a NO_x pollutant concentration monitor, a diluent monitor for either CO_2 or O_2, and a DAHS. (It is not necessary to install a flow monitoring system on the individual units if there is a flow monitor on the common stack.)

If a utility plans to install new NO_x CEMS for the early election units, then the DR should submit a revised monitoring plan on a date no later than the date the DR submits a Phase I NO_x compliance plan indicating that the units will be early electing. Each NO_x CEMS should be installed and provisionally certified no later than January 1, 1997.

Part 76 states that each individual early election unit must demonstrate that it meets the Phase I NO_x emission limitation each year, starting from the effective date of the early election through December 31, 2007 (see 40 CFR 76.8(e)(3)(i)). If units share a common stack and the NO_x emission rate is measured only on the common stack, it is not possible, without additional information, to determine if each individual unit actually met the Phase I NO_x emission limitation. Thus, monitoring on the common stack with a stack NO_x CEMS may not ensure compliance with the requirement in 40 CFR 76.8 that each individual early election unit meet the Phase I emission limitation.

The restrictions on early election unit averaging are consistent with this approach. Under Part 76, early election units are not allowed to participate in an emissions averaging plan before the year 2000. An early election unit may participate in an emissions averaging plan in the year 2000 or thereafter. However, the revised Phase II emission limitation must be used for that unit in the calculation to determine whether there is group compliance with the plan.

EPA will consider approving early election plans with just a single, common-stack NO_x monitor in the following circumstances:

(1) The utility may monitor for NO_x on the common stack and show that the group of units on the stack meets, on an average basis, the strictest of the NO_x emission limitations applicable to one or more of the units if:

(a) Every unit sharing the common stack is an early election unit, and each of the units using the common stack has installed low NO_x burner technology (LNBT); and

(b) EPA's Acid Rain Division concludes that the DR has demonstrated that each unit is currently meeting and is capable of continuing to meet the applicable Phase I NO_x emission limitation individually until January 1, 2007. Two acceptable ways of demonstrating this are to show that either:

(i) Each of the units using the common stack has installed LNBT with a performance guarantee that the unit will meet the Phase I limitation, and the performance guarantee has been met for each unit. In making this demonstration, the utility must provide the performance data and resulting report for each unit from the acceptance testing required under the contract with the LNBT vendor; or

(ii) Each of the units using the common stack has installed LNBT that is not guaranteed to meet the applicable Phase I NO_x emission limitation, and each unit meets the Phase I emission limitation, based upon at least 720 operating hours of quality-assured monitored NO_x emission rate data. The 720 operating hours of data must either be from (1) a certified CEMS installed on the common stack, when the unit is the only boiler emitting to the common stack, or (2) EPA reference methods 7E and 3A in Appendix A of 40 CFR Part 60 measured in the duct from each unit. In addition, it must be shown that the data were obtained during a period representative of normal operation of the unit.

(2) The utility may monitor for NO_x on the common stack and the DR may demonstrate that each unit is meeting the applicable Phase I NO_x emission limitation individually if the DR petitions the Agency for a means for apportioning NO_x emissions from a common stack monitor, subject to approval by EPA's Acid Rain Division. The utility must demonstrate to EPA's satisfaction that the apportionment methodology ensures the complete and accurate estimation of NO_x emission rate to each unit. EPA notes that these requirements are difficult to meet; to date, no petitions for

NO_x apportionment from a common stack have been approved.

For further background on this issue, see Draft Acid Rain NO_x (Part 76) Policy Manual, April 1994, Question 5.1; and see Appendix B to the Acid Rain Program Policy Manual, Letter from M. Sheppard, EPA: Acid Rain Division to M. Cashin, Minnesota Power and Letter from L. Kertcher, EPA: Acid Rain Division to R. J. Gronquist, Jamestown Board of Public Utilities.

References: § 75.17, § 75.31, 40 CFR Part 75, App. A (2.1.2.1), § 76.5, § 76.7, § 76.8(a)(5), § 76.11

Key Words: Common stack, Early election, NO_x averaging

History: First published in October 1996, Policy Manual Update #10; retired in October 1999 Revised Manual